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**SPE 173739**

## **Reservoir Simulation and Near-Well Bore Modelling to Aid Scale Management in a Low Temperature Development with Multilateral Wells**

O. Ishkov, E.J. Mackay, O. Vazquez, Heriot-Watt University; M.M. Jordan, Nalco Champion

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### **Abstract**

This paper presents results of a reservoir and near wellbore modelling study to assist with the evaluation of inorganic scale risk management for a cold sandstone reservoir in the Norwegian sector of the North Sea. Reservoir temperature is in the range 32–48°C and poses a challenge to manage the scale risk.

The field is heavily supported by aquifer water, and the development includes five production wells and seven seawater injection wells. The small number of high-cost, highly productive subsea multilateral wells with long horizontal sections, some with sliding sleeves to enhanced flow management, coupled with a high barium sulphate scaling tendency (up to 350ppm barium concentration in the formation water) requires effective scale management.

This paper addresses questions of timing and nature of seawater breakthrough, when scale inhibitor squeeze treatments will be required, what is the impact of any reservoir reactions between the formation water and injected seawater on the scale risk at the production wells, what squeeze placement profiles look like under a range of squeeze treatment scenarios (various injection rates and sleeve position options). The treatment of multilateral wells by bullhead scale squeeze treatments is not a subject extensively covered in the literature, so the focus of this paper is to understand the impact on squeeze treatment life of bullhead deployment as a function of pump rate with both laterals open and the impact on treatment lifetime and treatment cost of selective placement into each lateral by treating one lateral at a time via activation of the sliding sleeve mechanism.

The paper draws on a wide range of technical inputs to make scale management decisions including: thermodynamic modelling techniques, reservoir simulation of fluid mixing and reaction, laboratory-generated coreflood data to assess chemical selection for scale inhibitor squeeze, and squeeze treatment design drawing on all the information outlined above.

Sharing the scale management technical challenges associated with such low temperatures and treating multilateral wells provides an example of the factors that should be taken into account during project design in similar fields under development in Northern Norway, offshore West Africa and offshore Brazil.

### **Introduction**

Sandstone reservoir located in the Norwegian sector of the North Sea contains oil with an overlying gas cap and lies approximately 1100 metres beneath the sea surface. Reservoir temperature is relatively low 32 – 48°C and poses a challenge from the risk of mineral scale point of view. Reservoir pressure is low as well – in the range of 120 –180 bara.

Water injection requires volumes greater than the water volumes expected to be produced. Produced water (PW) volumes are estimated to be 12 000 sm<sup>3</sup>/day, while total injection is designed to be 20 000 sm<sup>3</sup>/day. Regulatory requirement for that particular area in the Norwegian sector of the North Sea is "Zero discharge" policy which dictates that there will be no produced water discharge during normal operation.

## Field overview

The first principal activity performed in this study enabled to identify the probable extent of the scaling problem. Authors have performed a scale risk study based on a reservoir model of the field developed and supplied by an operator.

Details of the mineral scale mechanisms are given elsewhere (Oddo and Tomson, 1994; Ramstad et al., 1999; Vetter et al., 1982; Jacques and Bourland, 1983; Vetter et al., 1970), as are the reasons why they pose problems in the production well, near-well areas and surface facilities (Mackay and Sorbie, 2000; Sorbie and Mackay, 2000; White et al., 1999), much less commonly in injection wells (Mackay et al., 2003a), and never deep within the reservoir (Bertero et al., 1988; Paulo and Mackay, 2001; Mackay, 2003). The various scale management techniques are also given elsewhere (Oddo and Tomson, 1994; Hinrichsen, 1998; Clemmit et al., 1985; Mendoza et al., 1999; Tanner and Wittingham, 1986; Børeng et al., 1994; Collins et al., 1997; Bourne et al., 1997; Jordan et al., 2001; Hardy and Simm, 1996; Davis et al., 1996; Vu et al., 2001), as are the particular considerations for deepwater systems (Graham et al., 2002; Mackay et al., 2003b; McElhiney, 2003). In recent years the integration of reservoir simulation into the scale risk evaluation process (Mackay et al., 2005) has resulted in extra information being available to assess the challenge of squeeze treatment placement and the impact of scale reactions within the reservoir impacting the produced water composition.

During the first stage the reservoir model was modified in such a way that the displacement of different types of brines can be tracked, and water volumes produced by each well and distribution of brine types produced by each well are calculated and analysed. Modifications and the addition of tracers to the reservoir model did not interfere with the initial case and no change in volumes produced observed.

The calculations using reservoir simulation software were performed to identify the volumes of fluid in place, and the proportions of each of the various brine types that should be expected throughout the field history (Figure 1). Figure 2 presents fluids in place with gas and water in place removed in order to display oil/water injection and production in more detail.

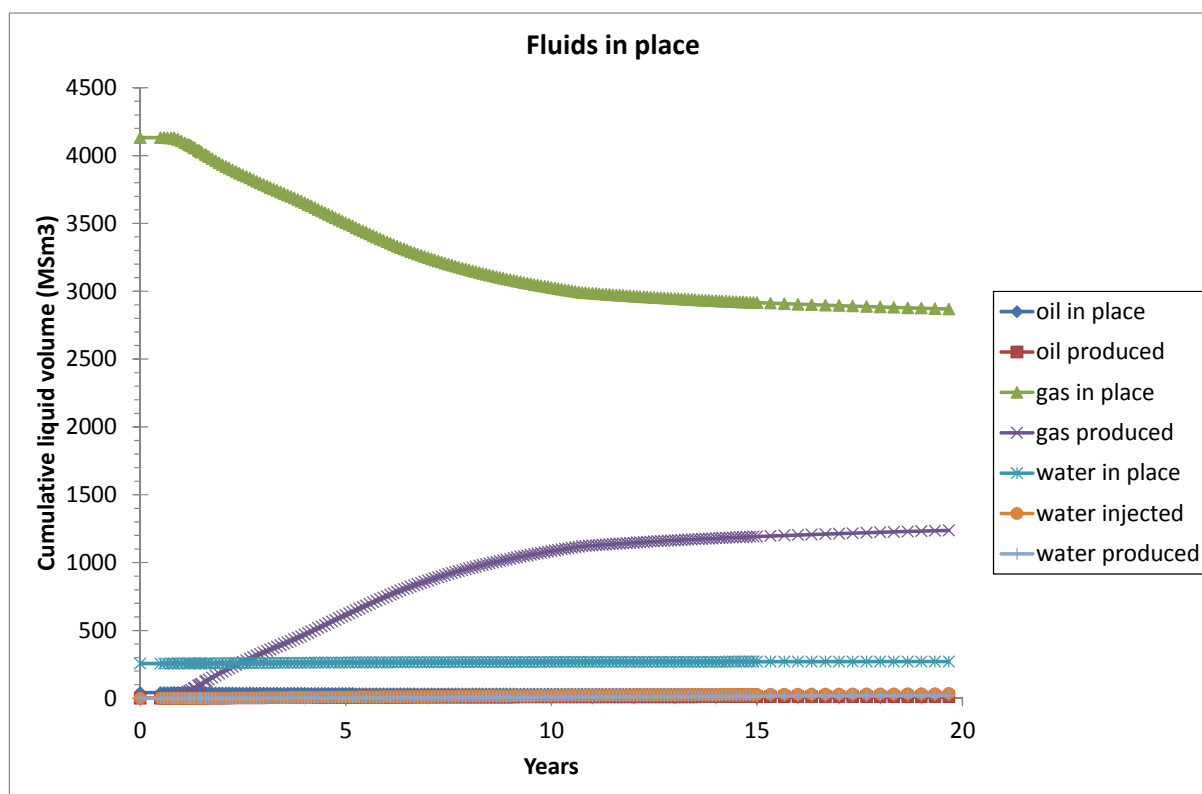
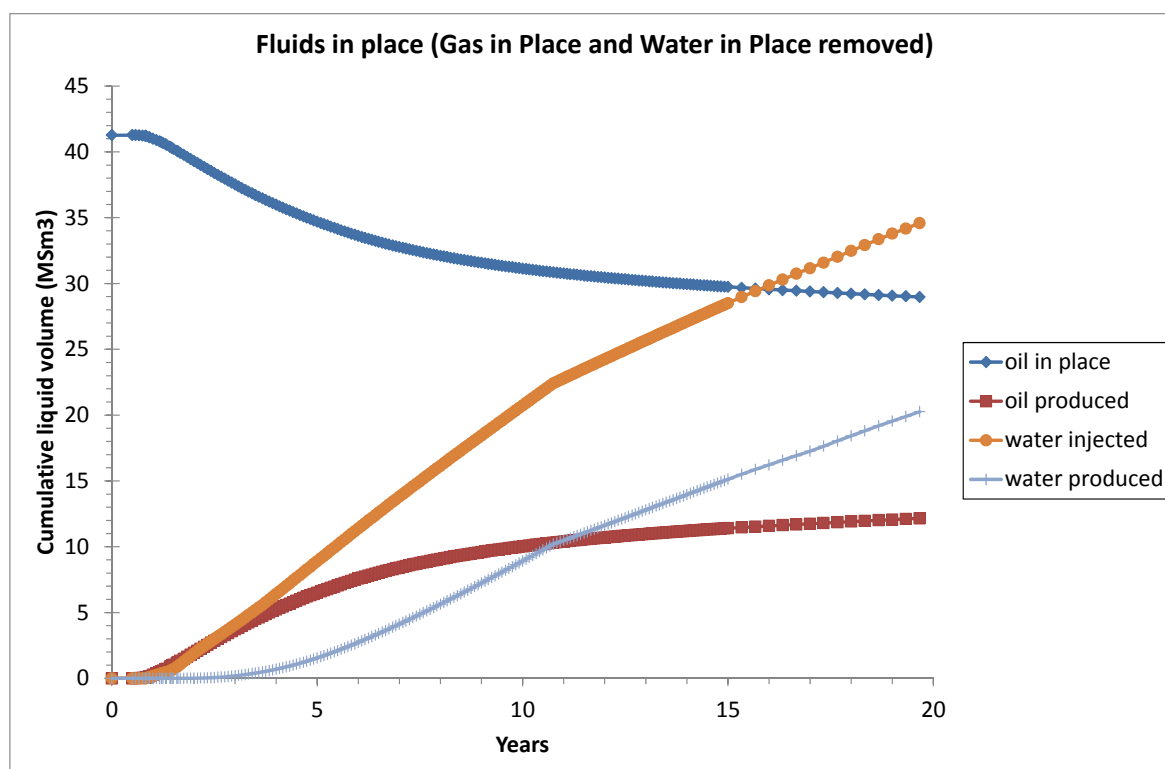


Figure 1 Fluids in place



**Figure 2 Fluids in place (Gas in Place and Water in Place removed)**

Profiles of water injected and produced indicate that there will be insufficient produced water to provide for the required injection rate, and therefore another source of injection water will also be required.

Brines in place plot (Figure 3) shows that the field has around 240 MSm³ of aquifer water and 18 MSm³ of connate water in place at the start. An additional 35 MSm³ will be injected according to the development plan (Figure 4). Significant water production will only take place after 5 years of production. The volume of water produced by the end of field life will exceed the volume of oil produced by around 2 times (10 MSm³ of oil vs 20 MSm³ of water on Figure 2).

The vast majority of water in place at all times will be aquifer water (Figure 3) and only around 5 MSm³ out of 35 MSm³ injected seawater is produced back. The majority of water produced is aquifer water - 10 MSm³, with production of 5 MSm³ of seawater and only 2.5 MSm³ of connate water (Figure 4).

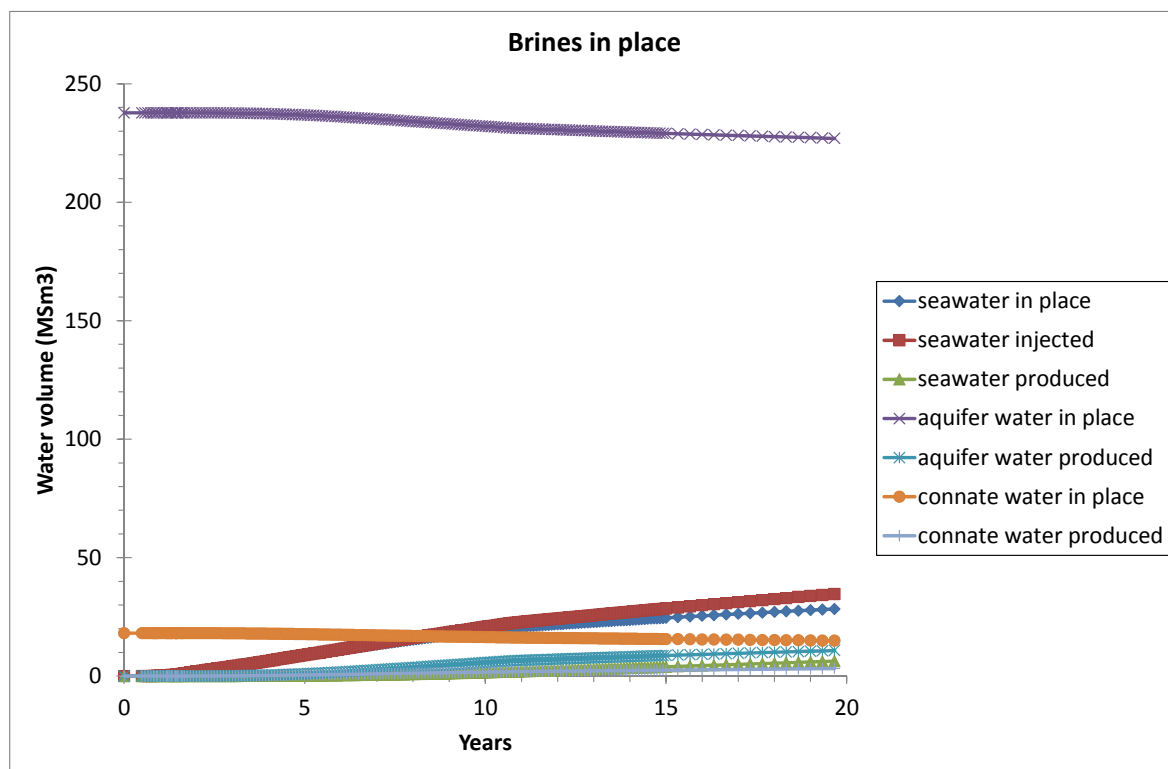


Figure 3 Brines in place

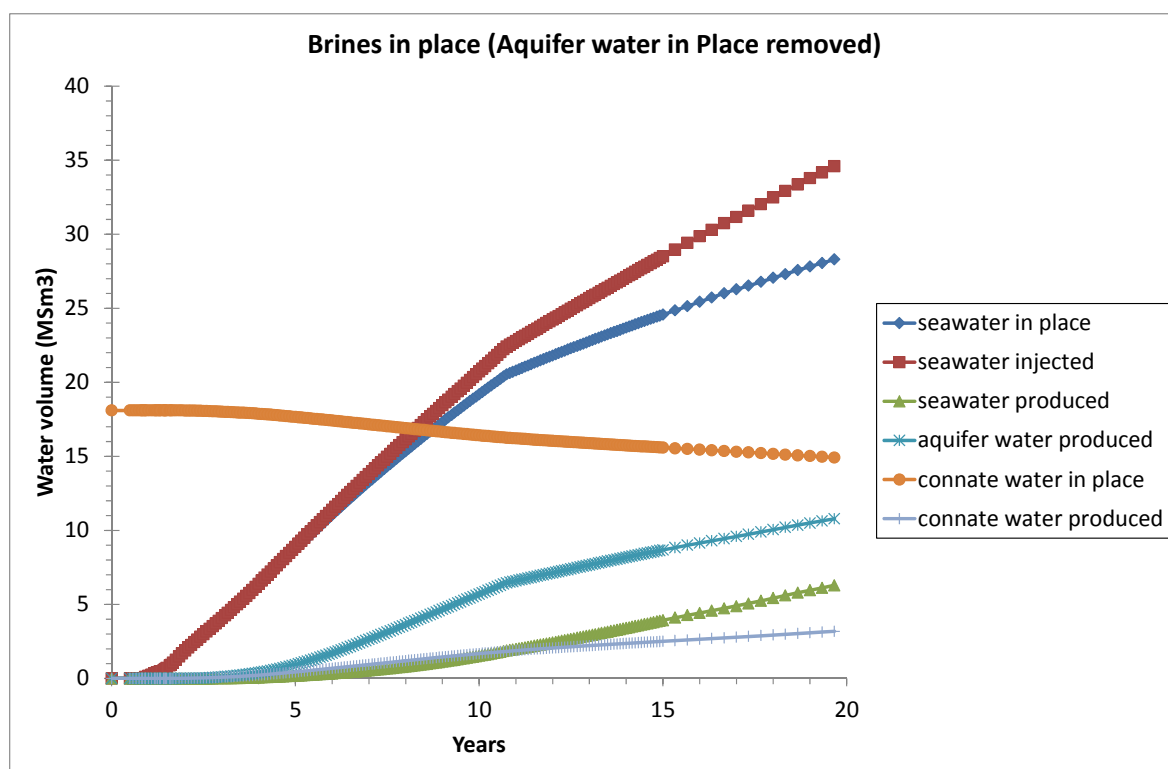
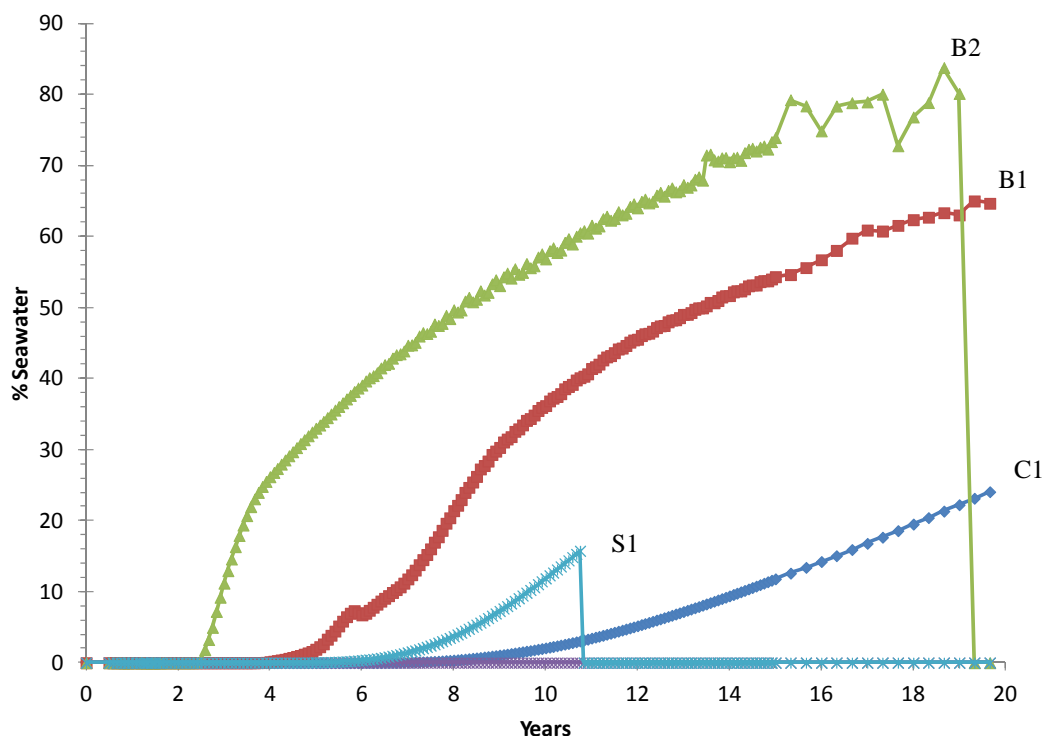


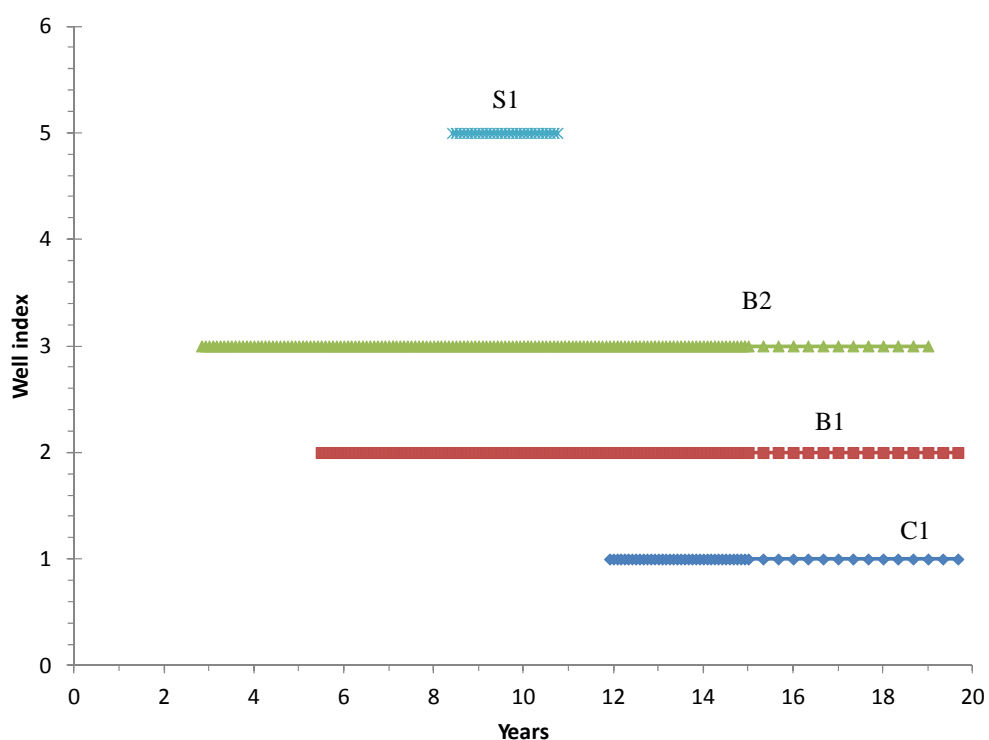
Figure 4 Brines in place (Aquifer water in Place removed)

The next principal activity is to identify wells under the most scaling risk. The fraction of seawater in the produced brine governs the severity and mass of mineral scale. Thus, studying mitigation of mineral scale risk we are as concerned with the fraction of seawater in the produced brine as we are with the total volume of water produced. Figure 5 shows percentage of seawater in the produced brine. Wells B2 and B1 produce significant amounts of seawater. These wells will have a significant mineral scale risk.



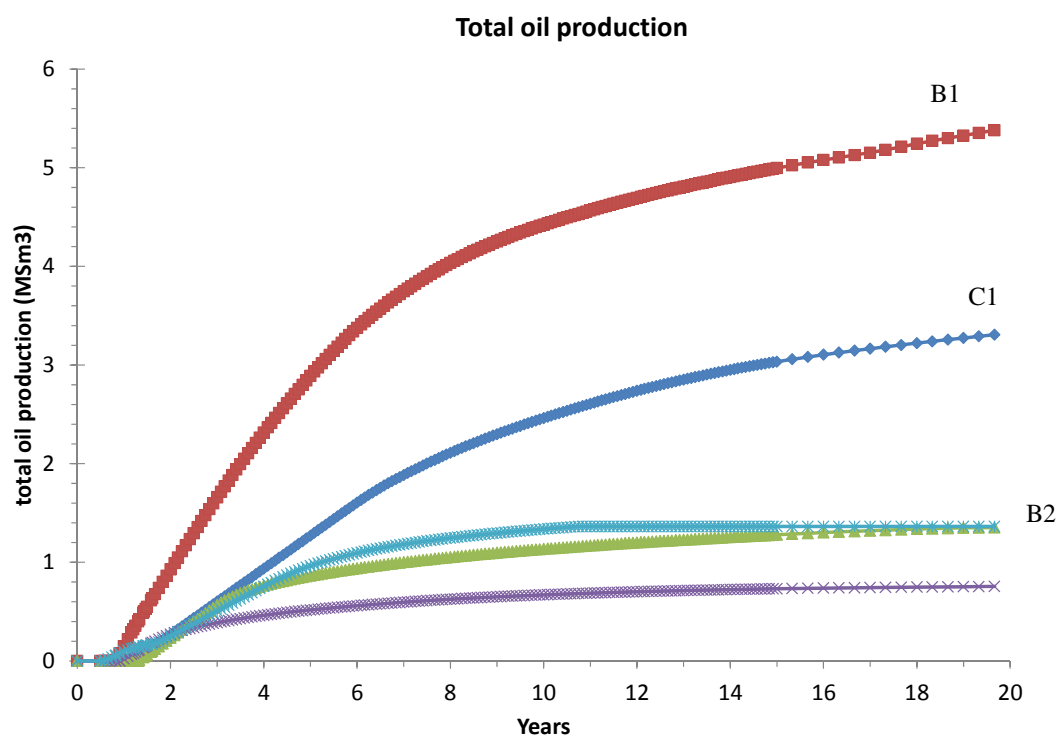
**Figure 5 Percentage of seawater in the produced brine**

The scale risk plot in Figure 6 is presented to indicate time periods when each well produces seawater above a certain limit. In this case limit was chosen to be 5% of seawater in the produced brine. Wells B1 and B2 were selected for the next stage of the analysis as they possess a significant scale risk.



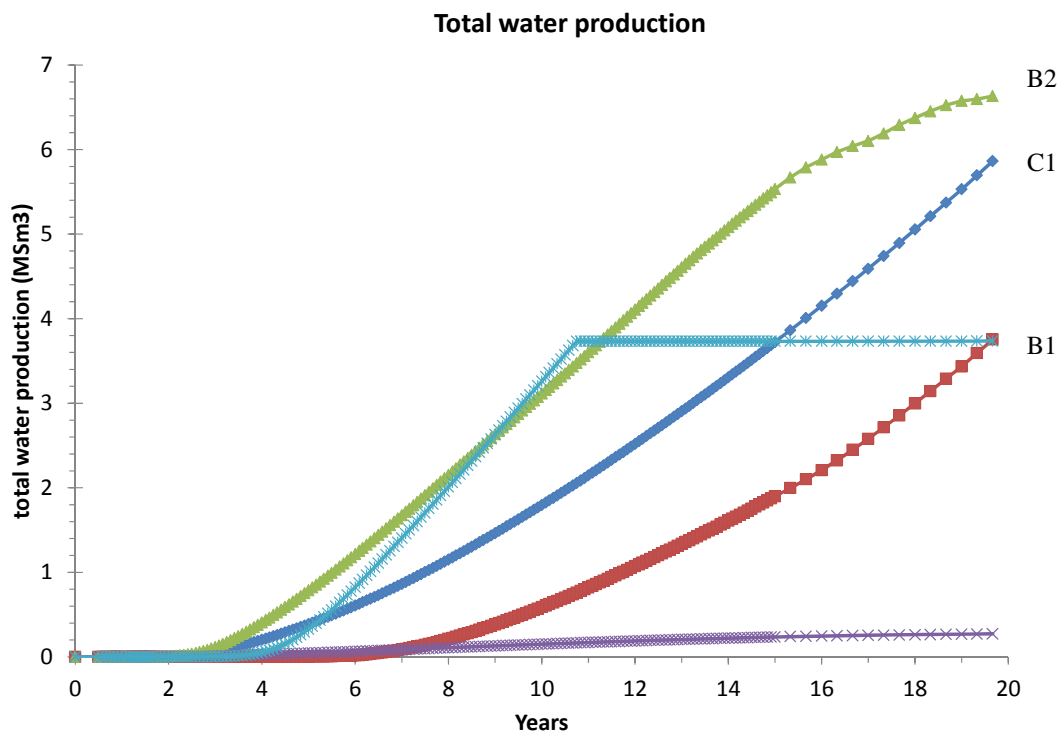
**Figure 6 Scaling risk**

B1 is the biggest producer with 5.5 SMm<sup>3</sup> of total oil produced (Figure 7), the second largest oil producer is C1 with 3 SMm<sup>3</sup> of total oil produced.



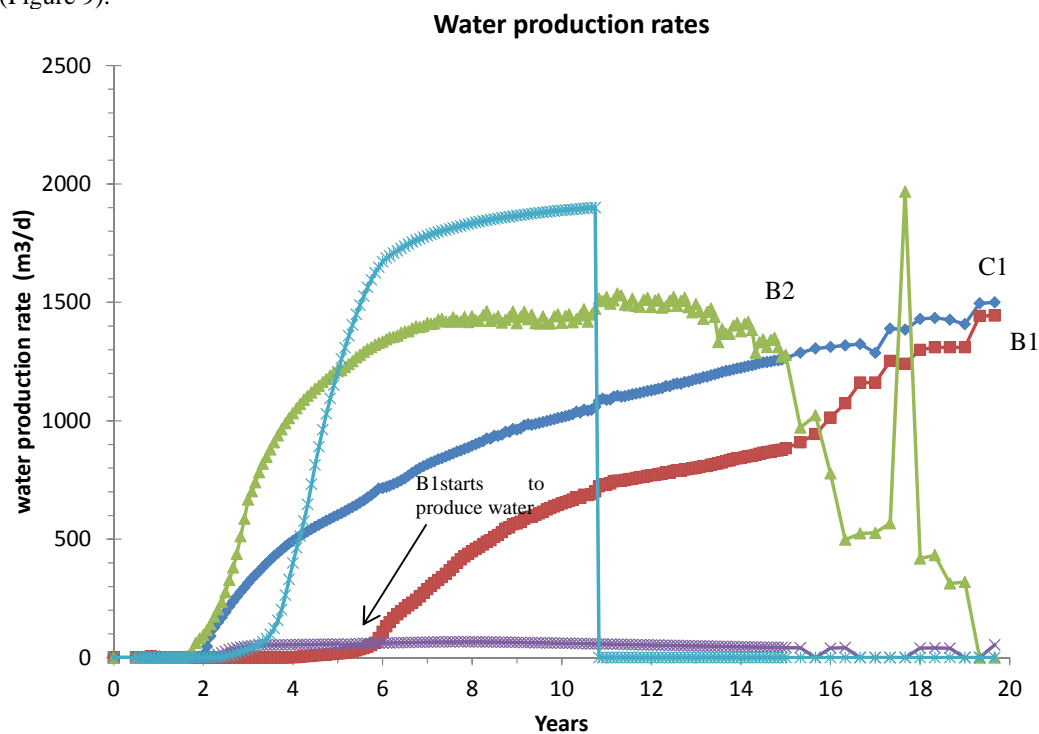
**Figure 7 Well total oil production**

Well B1 being the biggest oil producer does not mean that it produces the largest volumes of water; in fact it is the third water producer with 4 SMm<sup>3</sup> (Figure 8).



**Figure 8 Total water production**

B1 has water breakthrough after 6 years of production, while all other wells start producing water after 2-3 years of operation (Figure 9).



**Figure 9 Water production rates**

Well B2 is a modest oil producer and the biggest water producer (Figure 8). Well C1 is a high oil producer and a high water producer. The volume of water it produces is twice as much as the volumes of oil it produces (3 SMm³ of total oil produced and 6 SMm³ of total water produced).



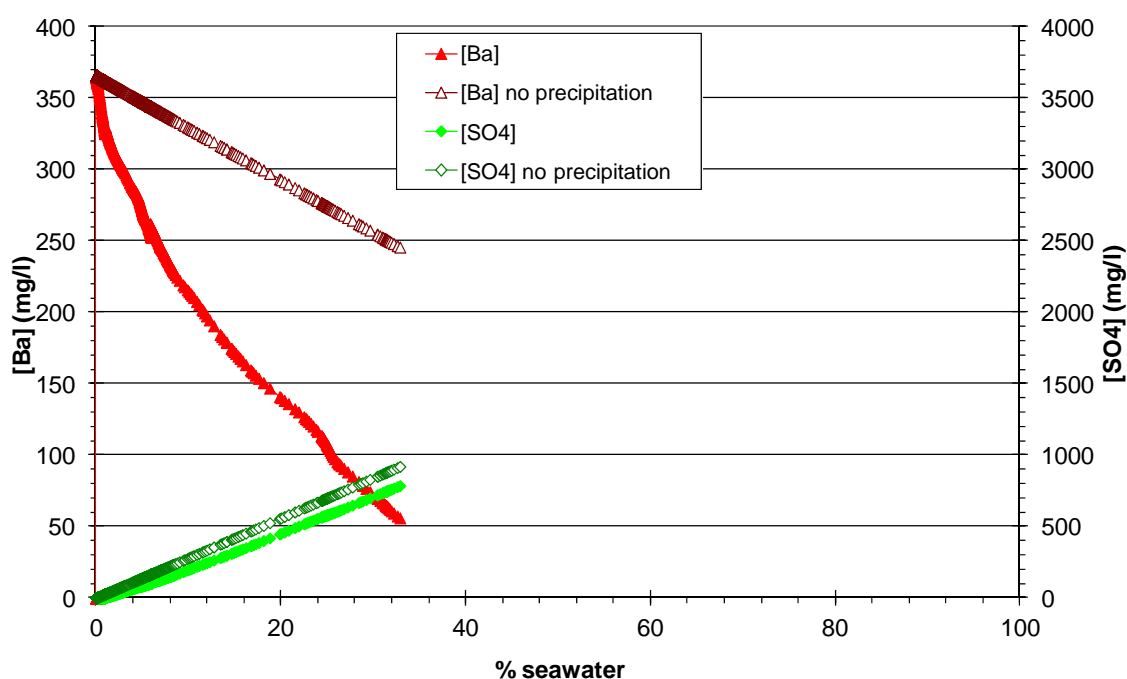
### Reactive Transport Modelling

The conventional reservoir simulator model of the oil field was adapted to run using the reactive transport reservoir simulator. This simulator includes the capacity for reaction calculations to be defined, and as such, the  $\text{BaSO}_4$  precipitation reaction was included in the model, to identify the impact of the occurrence of this reaction in the reservoir on the composition of the brine at the producers. A corresponding permeability impairment was not modelled, but the change in porosities resulting from  $\text{BaSO}_4$  deposition deep in the reservoir are sufficiently small that any change in permeability will be negligible. The Formation water and injected seawater compositions assumed are shown in Table 1.

FORMATION WATER AND INJECTION WATER COMPOSITIONS												
mg/l	Na	K	Mg	Ca	Ba	Sr	Fe	Cl	Br	SO <sub>4</sub>	HCO <sub>3</sub>	TDS
Formation water	39600	466	772	3030	366	626	0	64200	0	0	2200	111260
Seawater	11150	420	1410	435	0	7	0	20310	0	2800	150	36682

**Table 1 — Formation Water and Injection Water compositions assumed in reactive transport modelling.**

The results for three wells that cut most water and seawater, B1, B2 and C1 are shown in Figures . The graphs show barium and sulphate concentrations plotted against seawater fraction, the latter being calculated using an inert tracer component (chloride). The reason for plotting the results in this way is that it allows comparison between the case with precipitation and the case with no precipitation, the latter being the straight dilution or mixing line. Thus, we can evaluate the impact that the precipitation reaction deep within the reservoir has on the produced brine compositions.



**Figure 10 Barium and sulphate concentrations predicted by reactive transport simulator for well B1.**

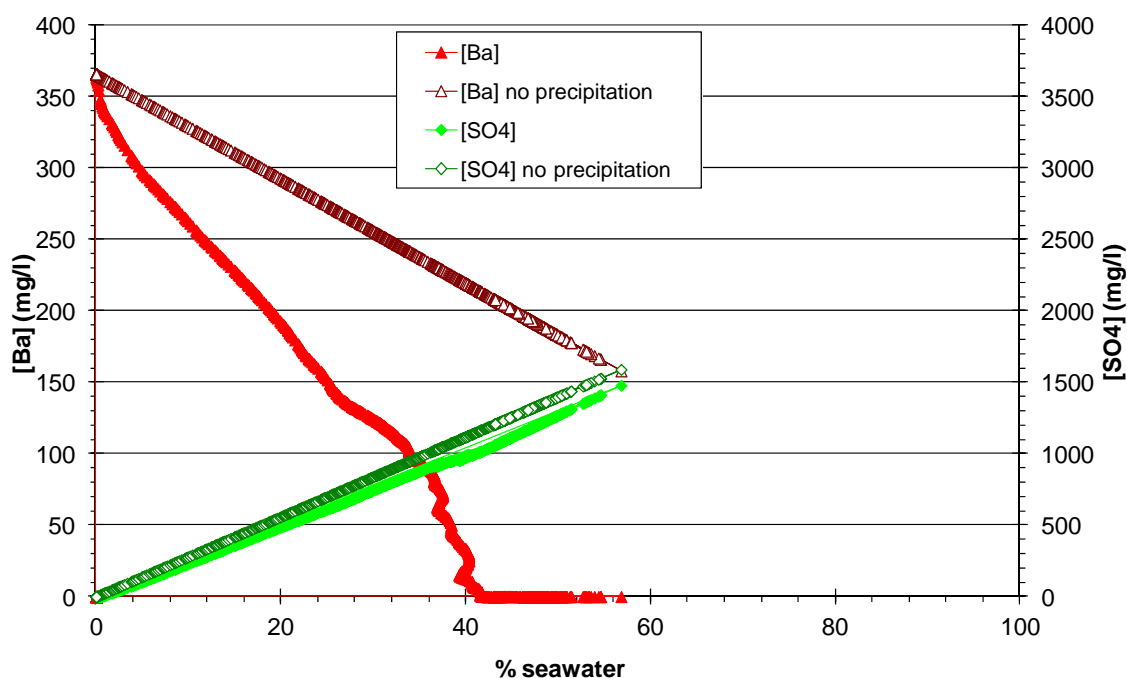


Figure 11 Barium and sulphate concentrations predicted by reactive transport simulator for well B2.

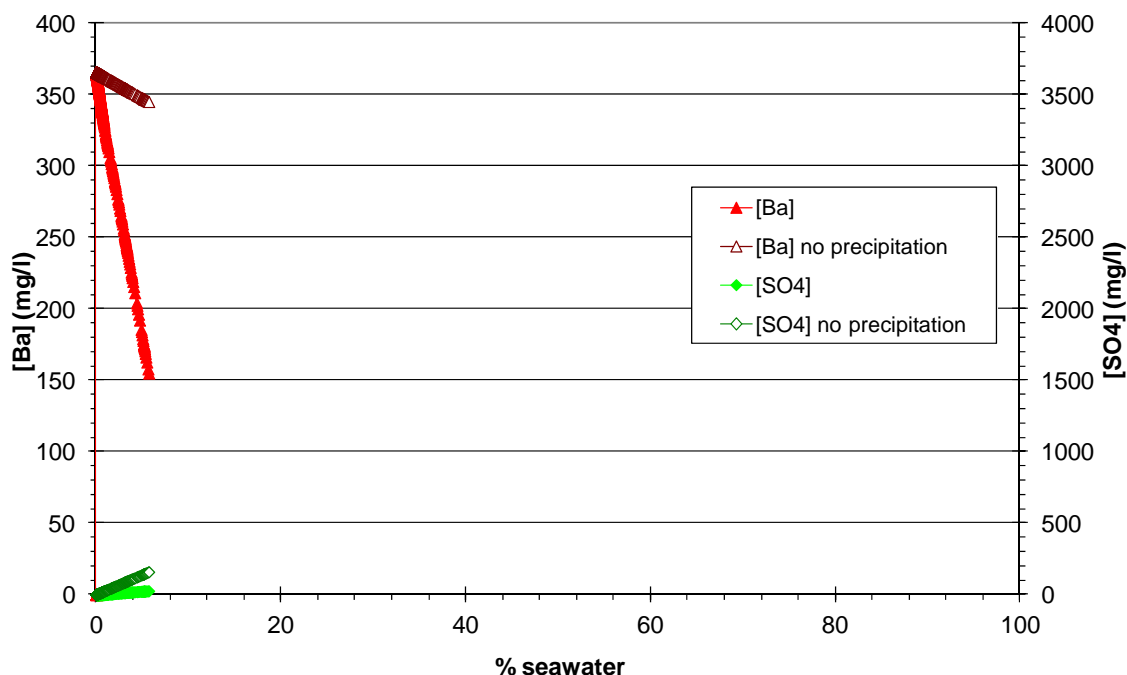


Figure 12 Barium and sulphate concentrations predicted by reactive transport simulator for well C1.

Although the simulation was terminated before the wells reached the final seawater fractions, it is the early time behaviour that is most significant, and it is evident that for each of the wells, the impact of precipitation deep in the reservoir is such that there is only a marginal impact on the relative sulphate concentrations (green) profiles with precipitation are close to the straight mixing line profiles without precipitation), there is significant depletion of the barium concentrations relative to their respective (red) mixing lines. This means that any chemical performance testing based on the full unreacted brines (as shown in Table 1), and not taking account of depletion in the reservoir, will be conservative – i.e. the tests will be based on a brine that is harsher than will actually be observed at the wells.

## Well results

The reservoir simulation model of the field was adapted and analysed to study the progression of the mixing zone towards the production wells in question, with a view to identifying what sections of the wells faced a scaling risk, and when the risk is the greatest.

This field is heavily supported by aquifer water and includes five production wells. The volume in the aquifer may restrict total breakthrough of seawater. However, individual well B1 and B2 produce high fractions of seawater (60% and 80% respectively).

Well B2 is chosen to be presented in this paper as it is the biggest water producer, and well B1 as it is a multi-lateral well.

For each of the selected wells a scale inhibitor squeeze placement calculation was performed using the reservoir model in to order to investigate injection profiles. No adsorption of scale inhibitor was modelled at this stage. Results per well are presented in this section of the paper.

## Well B2

Well B2 produces over 1SMm<sup>3</sup> of oil and over 6.5SMm<sup>3</sup> of water over 19 years, with water breakthrough after 0.5 years from start or approximately in the 2nd year of field production (Figure 7, Figure 8). This well is the greatest water producer. Water rises to 1400 m<sup>3</sup>/d, level for 10 years and declines after a further 4 years (Figure 9). B2 is the first well to experience seawater breakthrough. The seawater fraction reaches 85% (Figure 5). Seawater first breaks through at the heel of the well, not the toe (Figure 13). A bullhead squeeze at 5 bpm in year 2 would be adequate to ensure good placement in the heel and midsection of the well, but the toe is unprotected (Figure 14). The toe region likely has a higher pressure than the heel, which is supported by the fact of cross-flow during the shut-in period (red lines in Figure 14). The later squeeze treatment in year 4 (2 years after the first one) shows seawater in the toe section with poor squeeze placement, and at this time 7 bpm is required to overcome cross-flow (Figure 15).

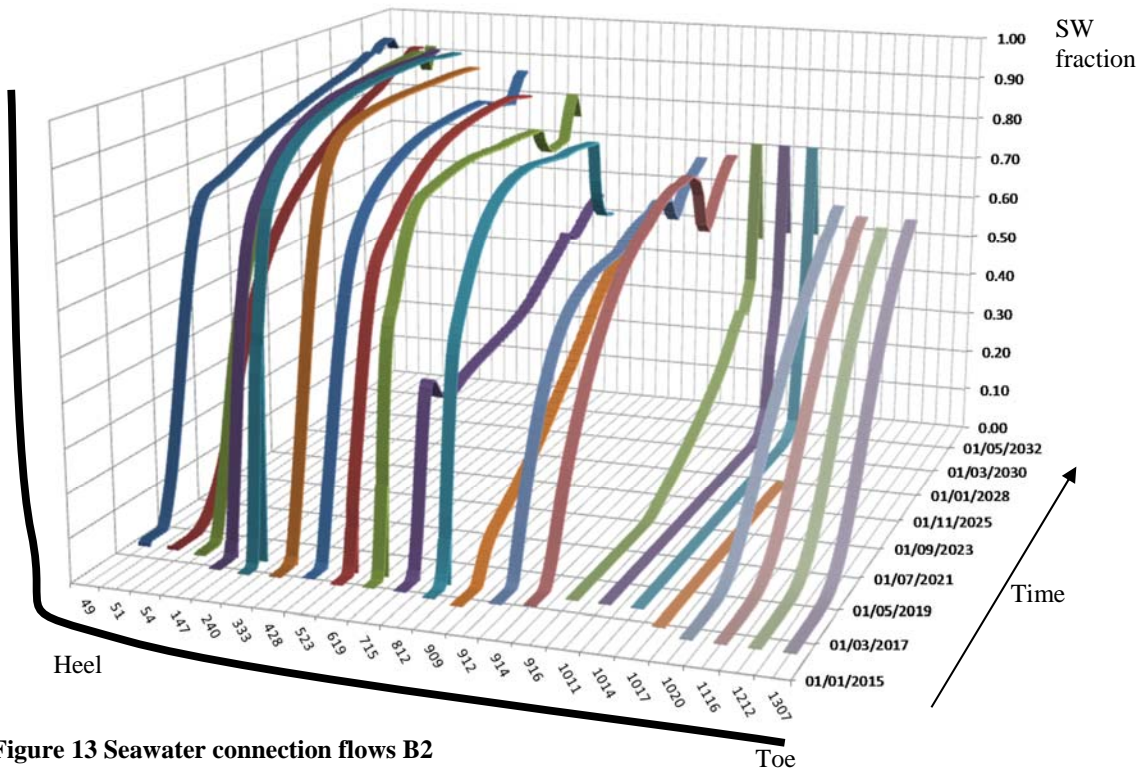


Figure 13 Seawater connection flows B2

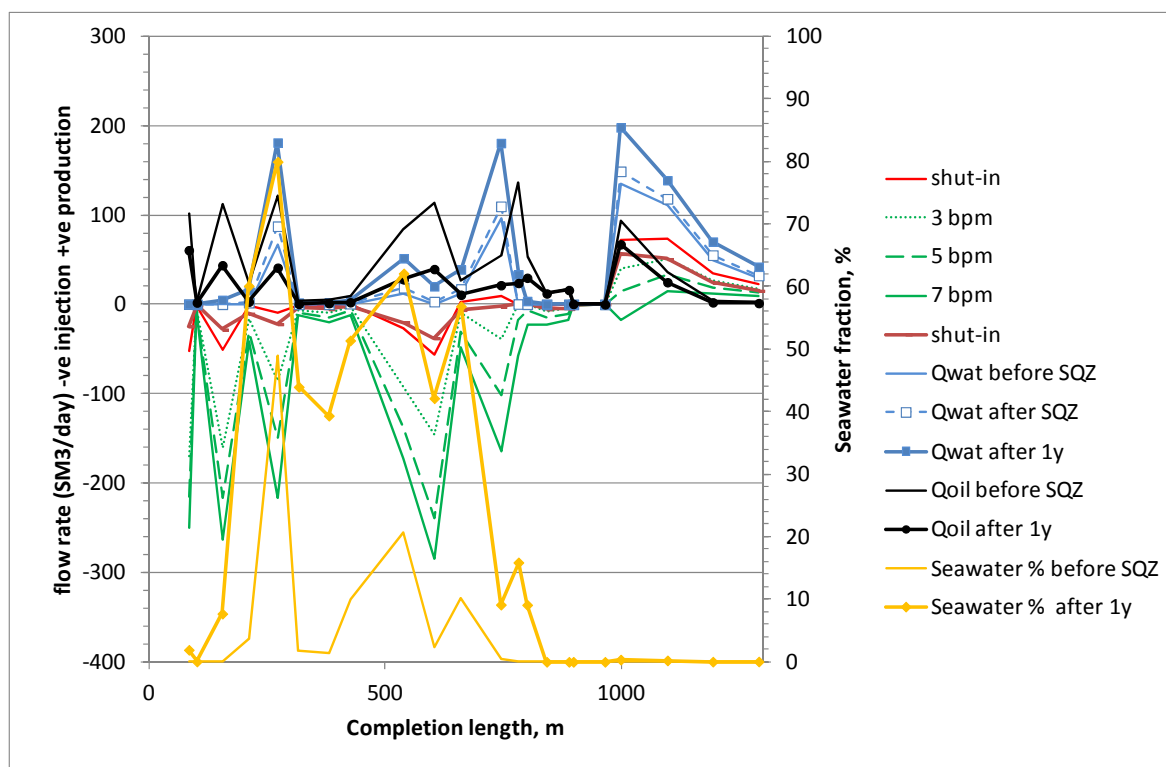


Figure 14 Well B2 connection flows for squeeze treatment at 1 Nov 2017

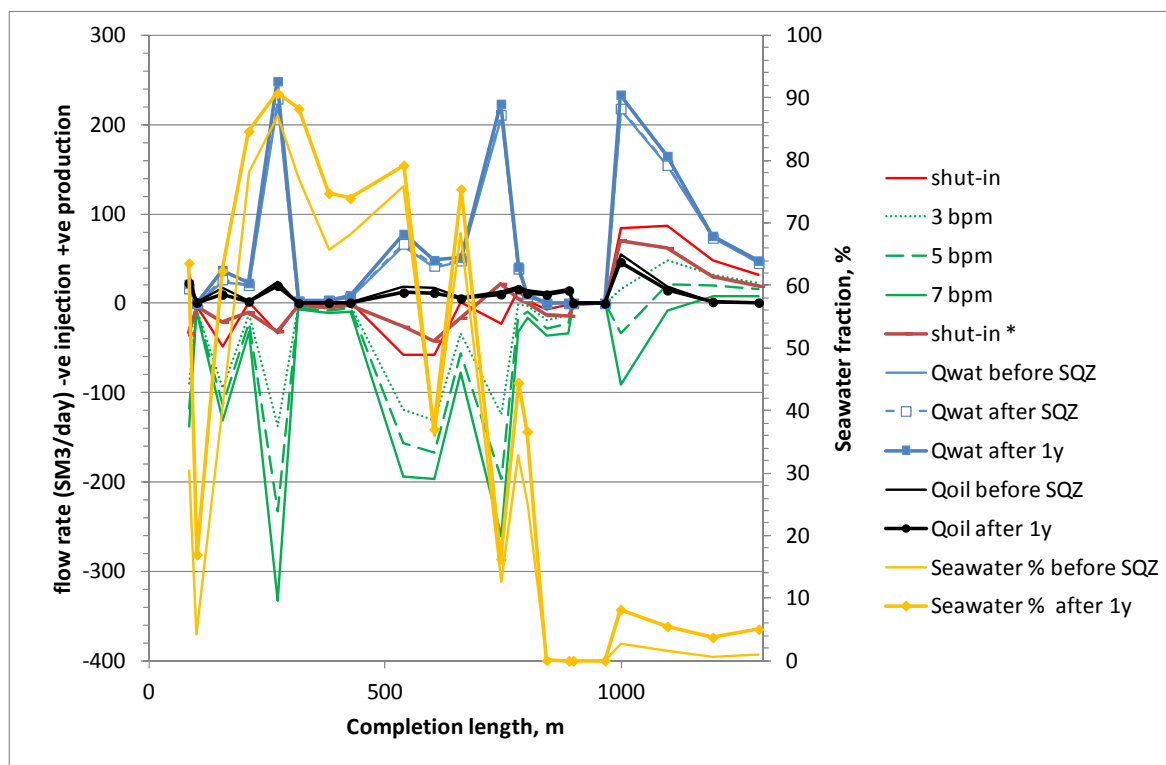


Figure 15 Well B2 connection flows for squeeze treatment at 1 Nov 2019 (2 years after the first one)

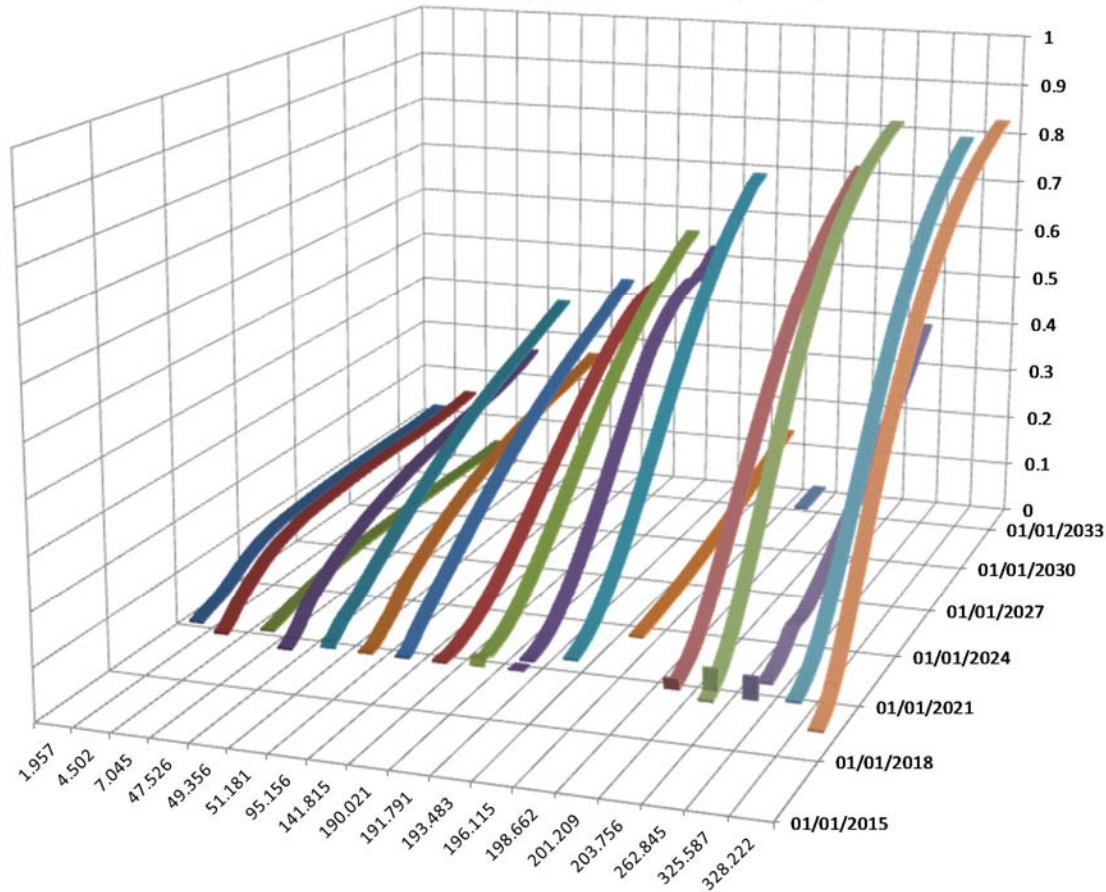
### Well B1

Well B1 is a multi-lateral well. Overall well B1 produces over 5.5 SMm3 of oil and around 4 SMm3 of water over 19 years, with water breakthrough after 5 years from the start of operation or approximately in the 5th year of field production (Figure 7, Figure 8). This well is the largest oil producer and is a medium water producer. Water gradually rises to 1300 m3/d (Figure

9). B1 is the second well to experience seawater breakthrough (year 5). The seawater fraction is high at the end of the well life, reaching 65% (Figure 5).

### **Segment 1**

Seawater in the well B1 Segment 1 breaks uniformly through the toe of the well first (Figure 16). A bullhead squeeze at 5 bpm in year 5 would be adequate to ensure good placement (Figure 17). The later squeeze treatment in year 10 (5 years after the first one) shows seawater in the toe section with good squeeze placement at 5-7 bpm (Figure 18). For the later squeeze cross-flow at the toe section (red line at Figure 18) may present a challenge during shut-in.



**Figure 16 Seawater connection flows for B1 Segment 1**

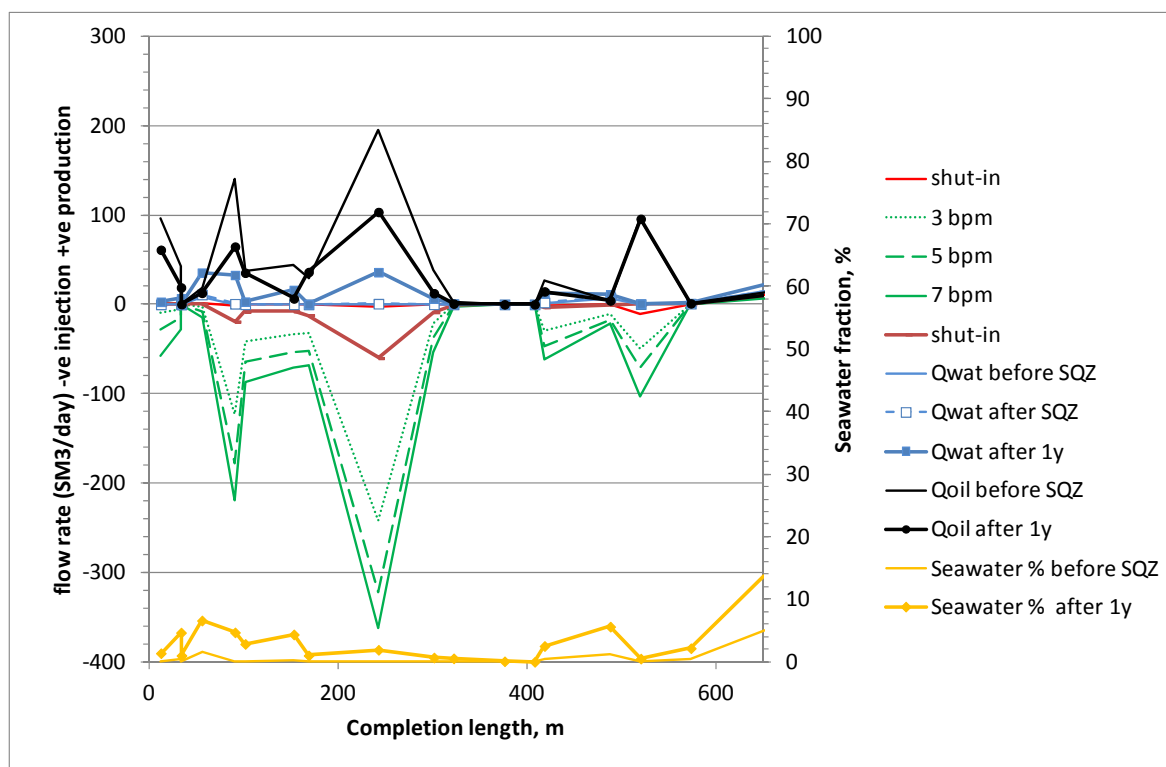


Figure 17 Well B1 Segment 1 connection flows for squeeze treatment at 1 Jul 2020

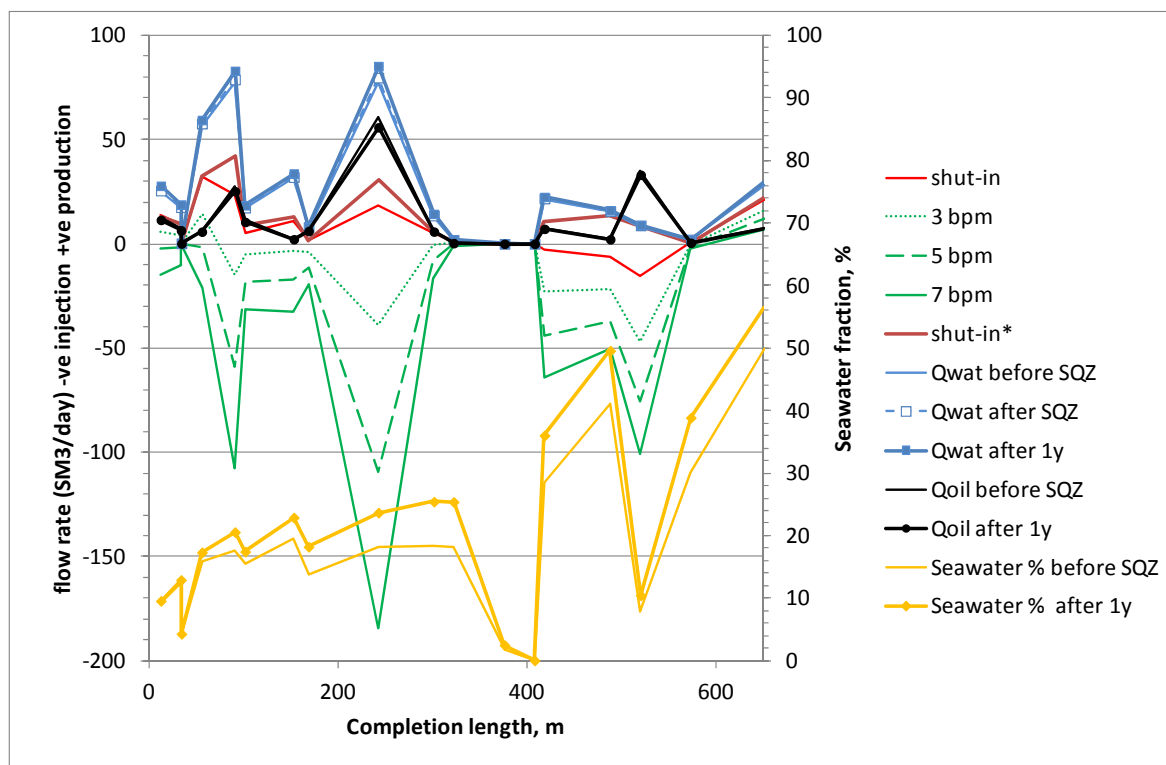


Figure 18 Well B1 Segment 1 connection flows for squeeze treatment at 1 Jul 2025

#### *Treatment when only Segment 1 is opened*

This section presents results of modelling a squeeze treatment in the well B1 Segment 1 when Segment 1 is the only opened lateral, as controlled by the ICV.

A bullhead squeeze at 5 bpm in year 5 would be adequate to ensure good placement (Figure 19). The later squeeze treatment in year 10 (5 years after the first one) shows more seawater in the toe section with good squeeze placement at 5-7 bpm (Figure 20). Use of the ICV allowed improvement of the squeeze placement and reduced cross-flow.

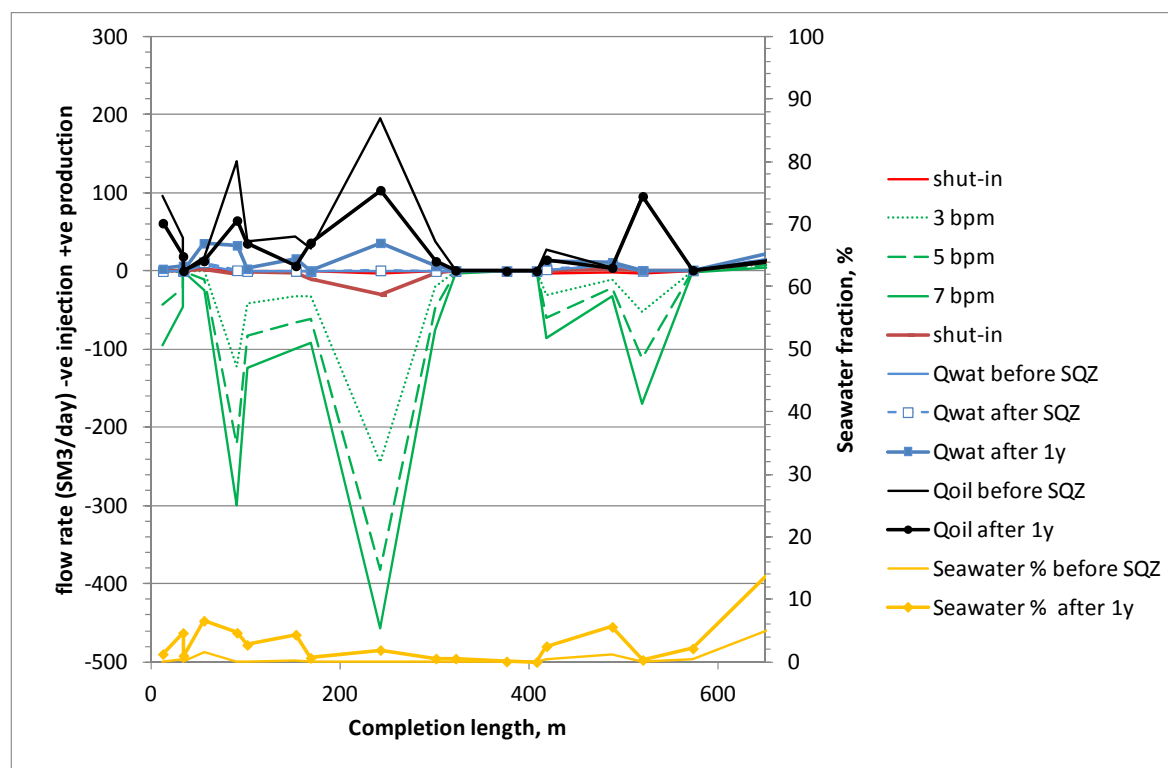


Figure 19 Well B1 segment 1 only connection flows for squeeze treatment at 1 Jul 2020

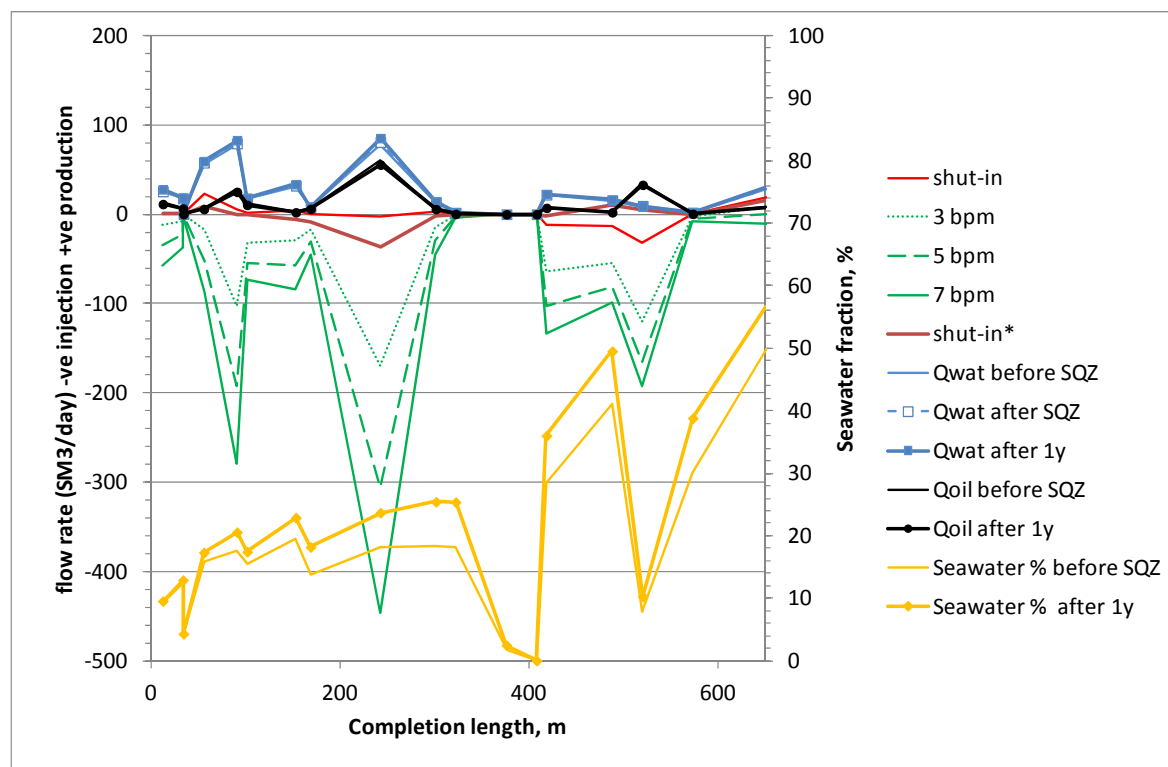
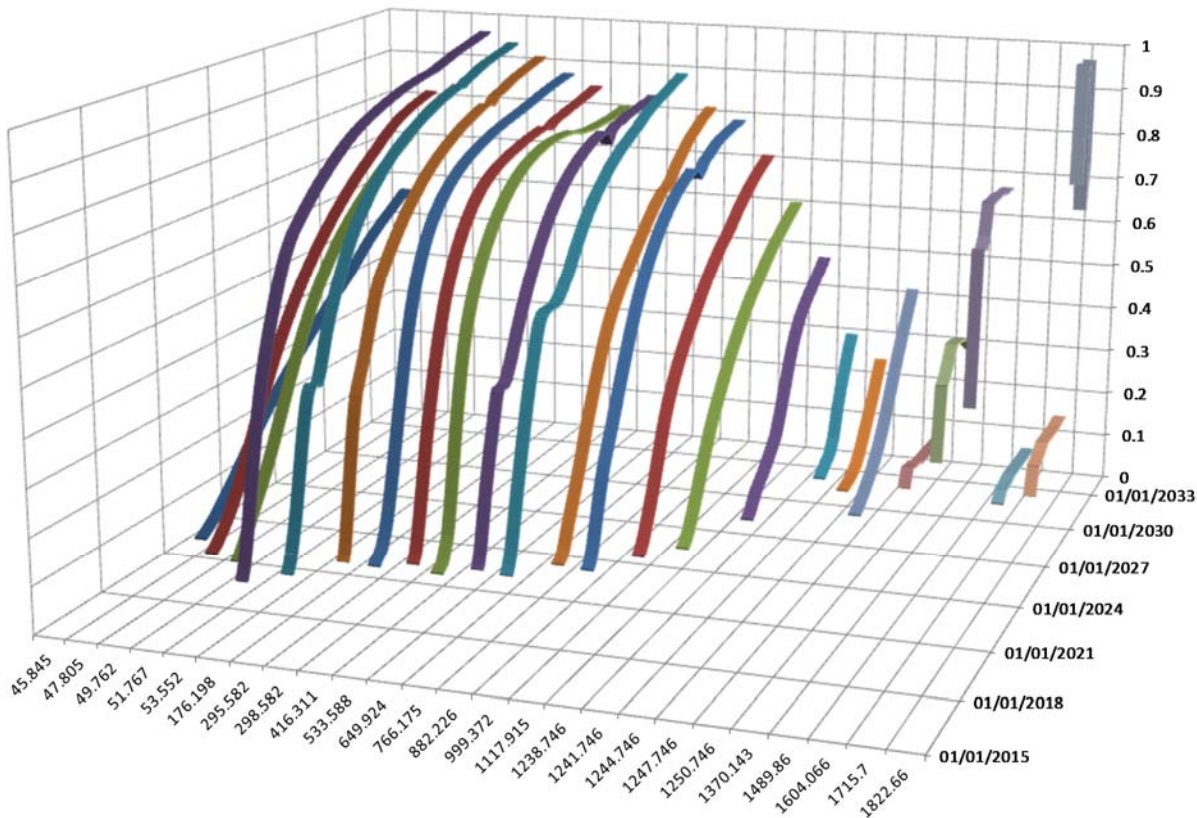


Figure 20 Well B1 segment 1 only connection flows for squeeze treatment at 1 Jul 2025



# **Segment 2**

Seawater in the well B1 Segment 2 breaks through mostly at the heel of the well, and then later is produced through the midsection, but not in the toe (Figure 21). A bullhead squeeze at 5 bpm in year 5 would be adequate to ensure good placement in the midsection and toe, but the heel is un-protected (Figure 22). Protection in this case can be assumed with the scale inhibitor flowing from toe to heel. A later squeeze treatment in year 10 (5 years after the first one) shows significant seawater breakthrough in the heel section (Figure 23). Squeeze treatment placement is a major challenge even at 7 bpm. At the later squeeze treatment cross-flow presents a significant challenge during shut-in.



**Figure 21 Seawater connection flows for B1 Segment 2**



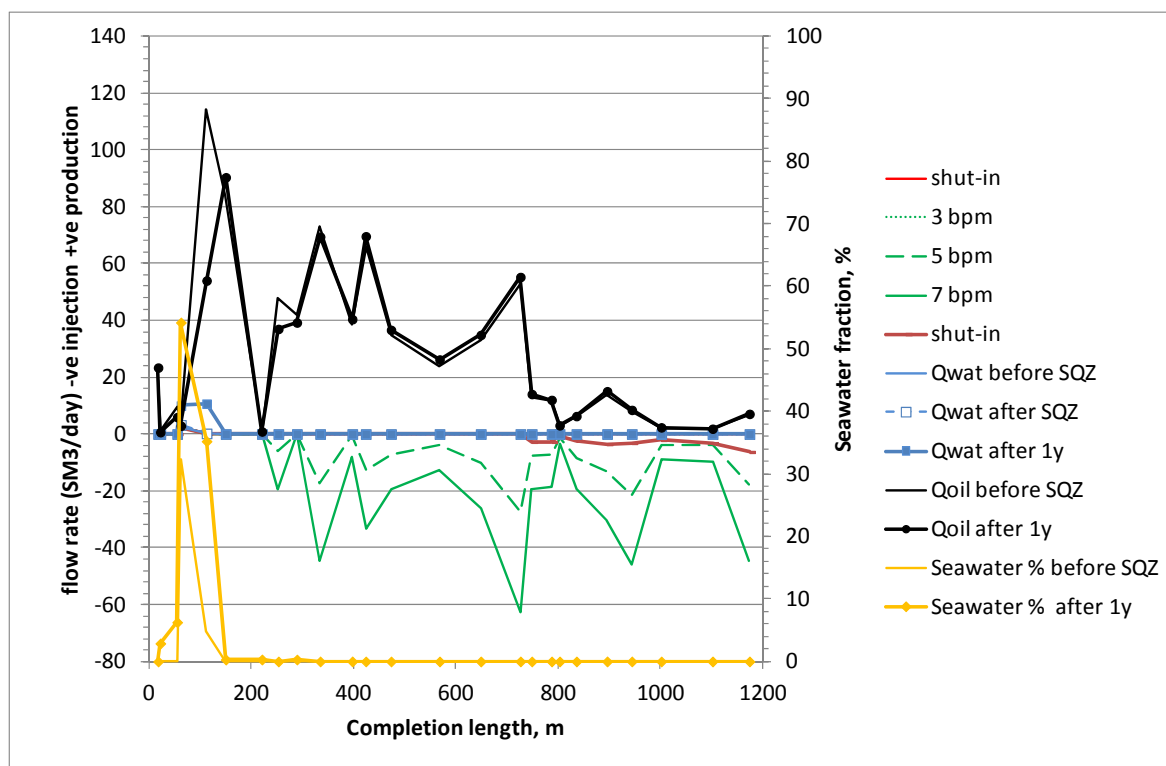


Figure 22 Well B1 Segment 2 connection flows for squeeze treatment at 1 Jul 2020

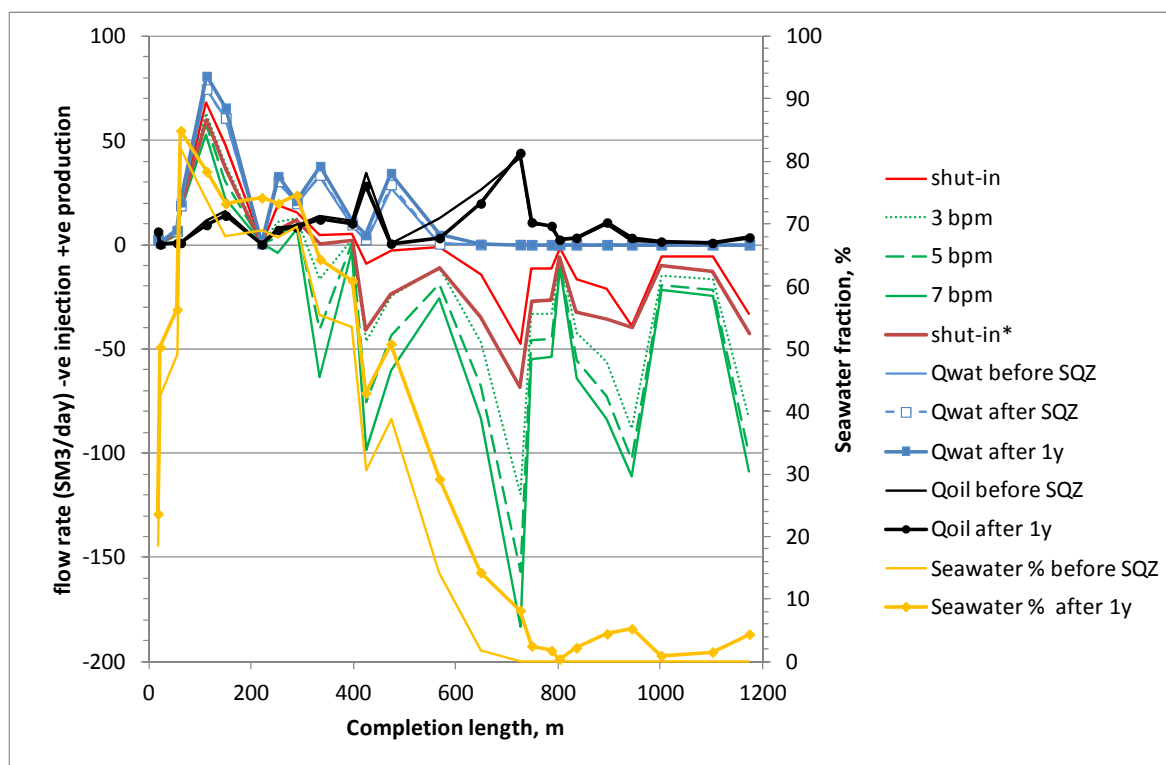


Figure 23 Well B1 Segment 2 connection flows for squeeze treatment at 1 Jul 2025

#### *Treatment when only Segment 2 is opened*

This section presents results of modelling squeeze treatment in the well B1 Segment 2 when Segment 2 is the only open lateral controlled by the ICV.

As when both laterals are open, a bullhead squeeze at 5 bpm in year 5 would be adequate to ensure good placement in the midsection and toe, but the heel is un-protected (Figure 24).

The later squeeze treatment in year 10 (5 years after the first one) with the ICV isolating lateral 1 is even more problematic, even at 7 bpm. Use of the ICV does not eliminate cross-flow during the shut-in.

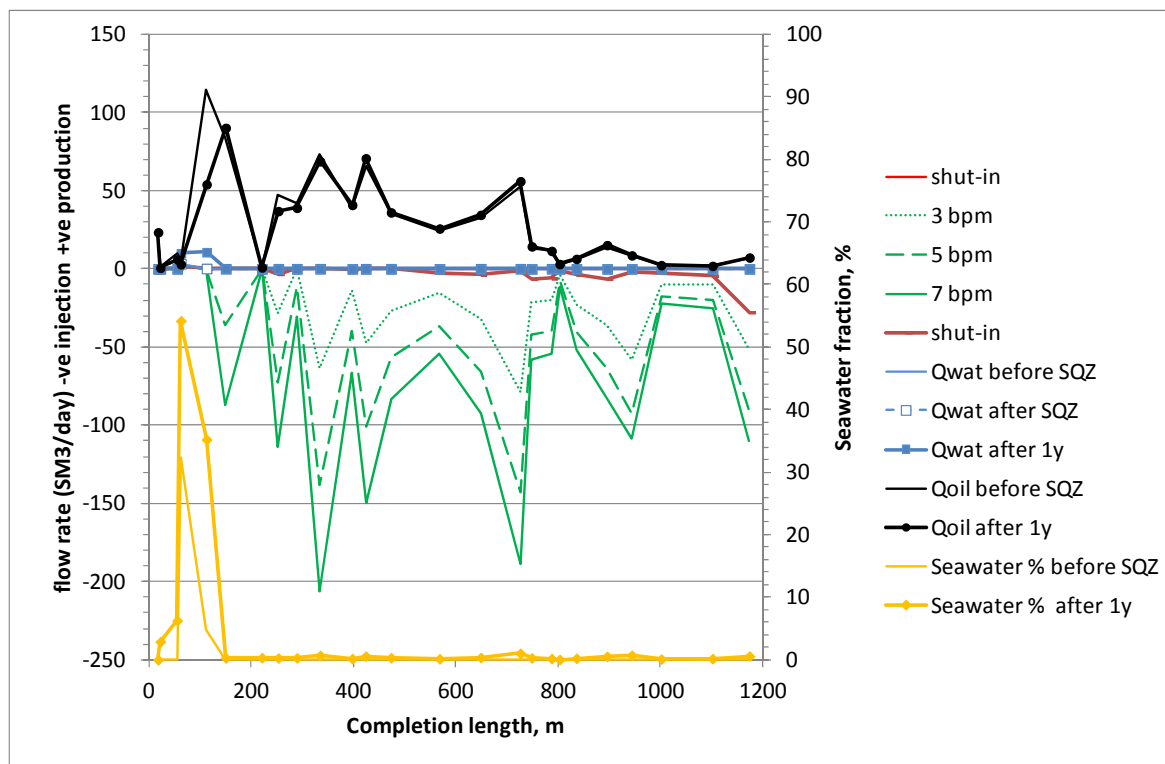
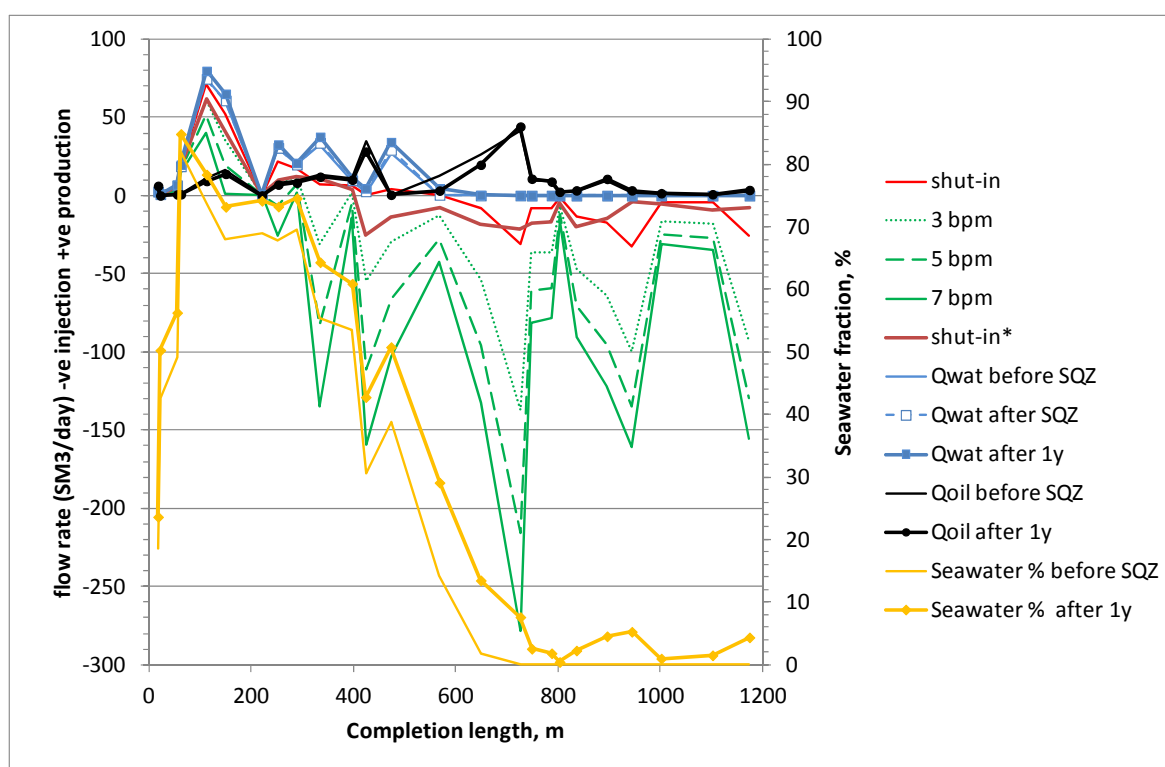


Figure 24 Well B1 Segment 2 only connection flows for squeeze treatment at 1 Jul 2020

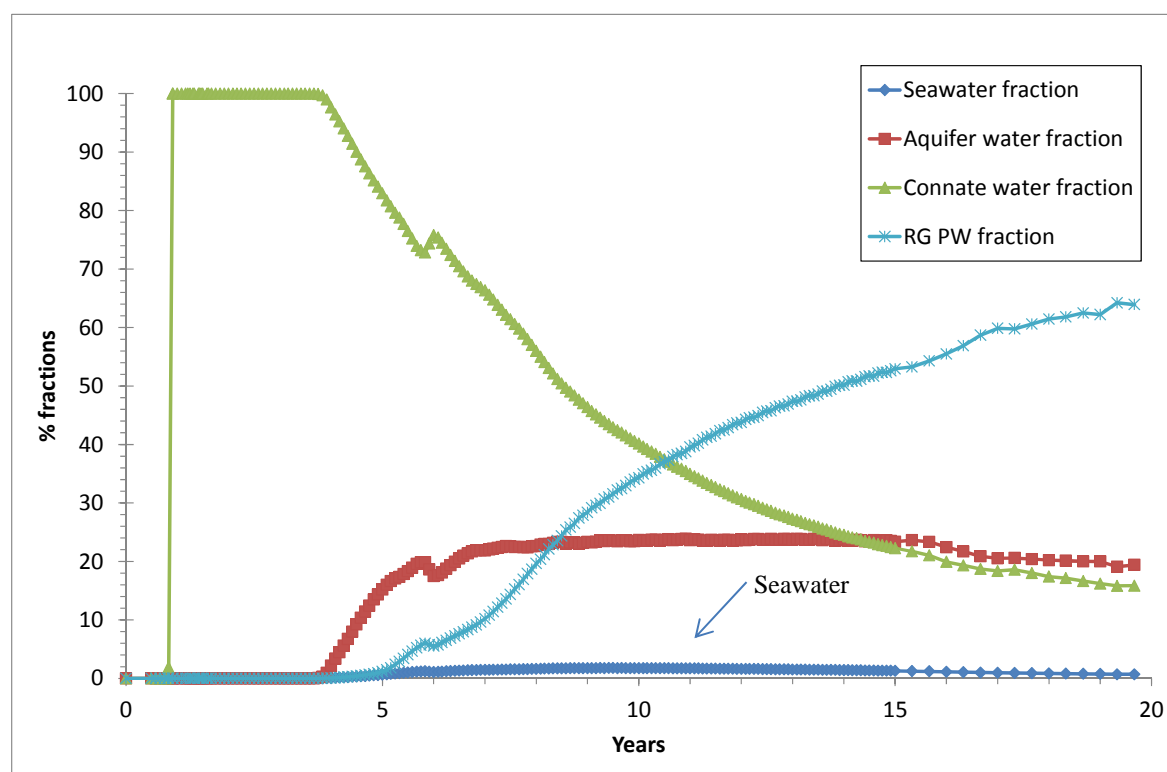


**Figure 25 Well B1 Segment 2 connection flows for squeeze treatment at 1 Jul 2025**

### Produced Water Re-Injection (PWRI)

This section reports results of the impact of replacing seawater with PWRI. In order to provide enough water volumes for pressure support the field development plan required the model to be run with the injection water being made up using seawater and produced water from another formation. Three scenarios were considered with the following sequence of injection: seawater is injected for either 1 year, 3 years or 5 years before the start-up of PWRI.

In the plots of fractions of produced brines (Figure 26 - Figure 31) Produced Water is associated with produced water from another formation. Injection water was made of 100% seawater in all cases. Therefore observations need to be focused on contrast between the breakthrough of Injection water (Seawater) and Produced Water (consisting of 100% water from a neighbor formation).



**Figure 26 Fraction of brines produced in the well B1 after 1 year of seawater injection followed by PWRI**

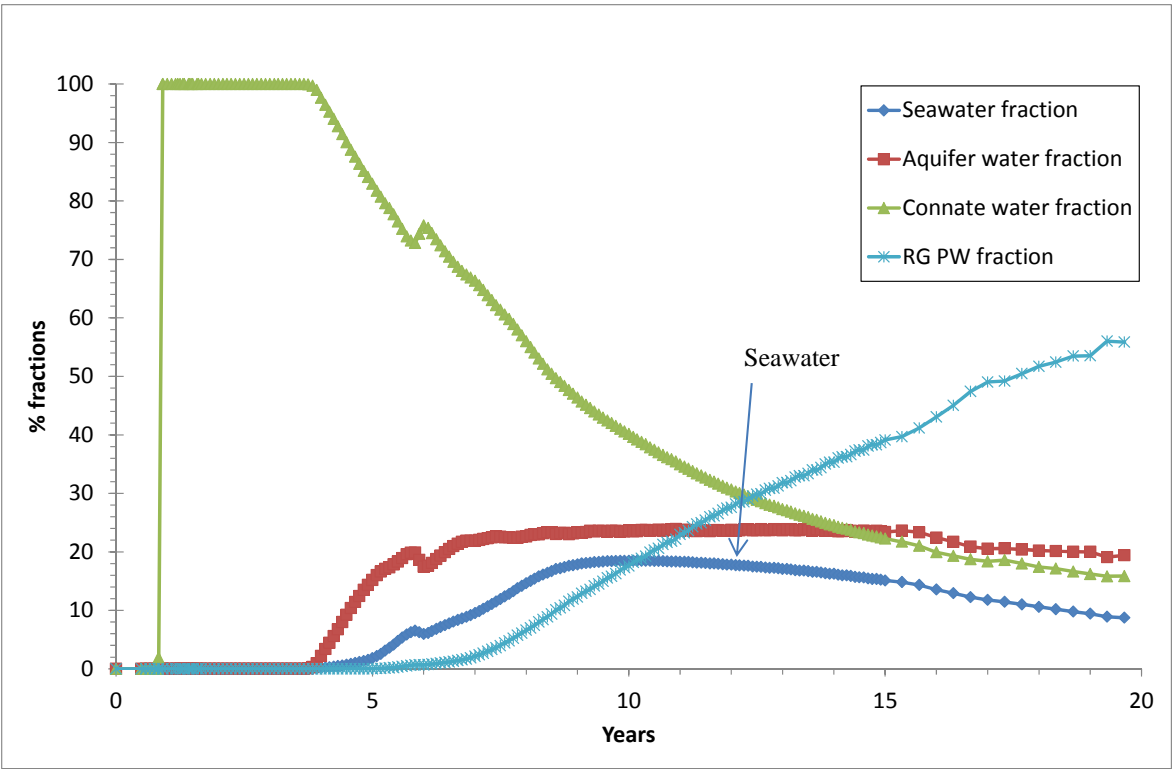


Figure 27 Fraction of brines produced in the well B1 after 3 years of seawater injection followed by PWRI

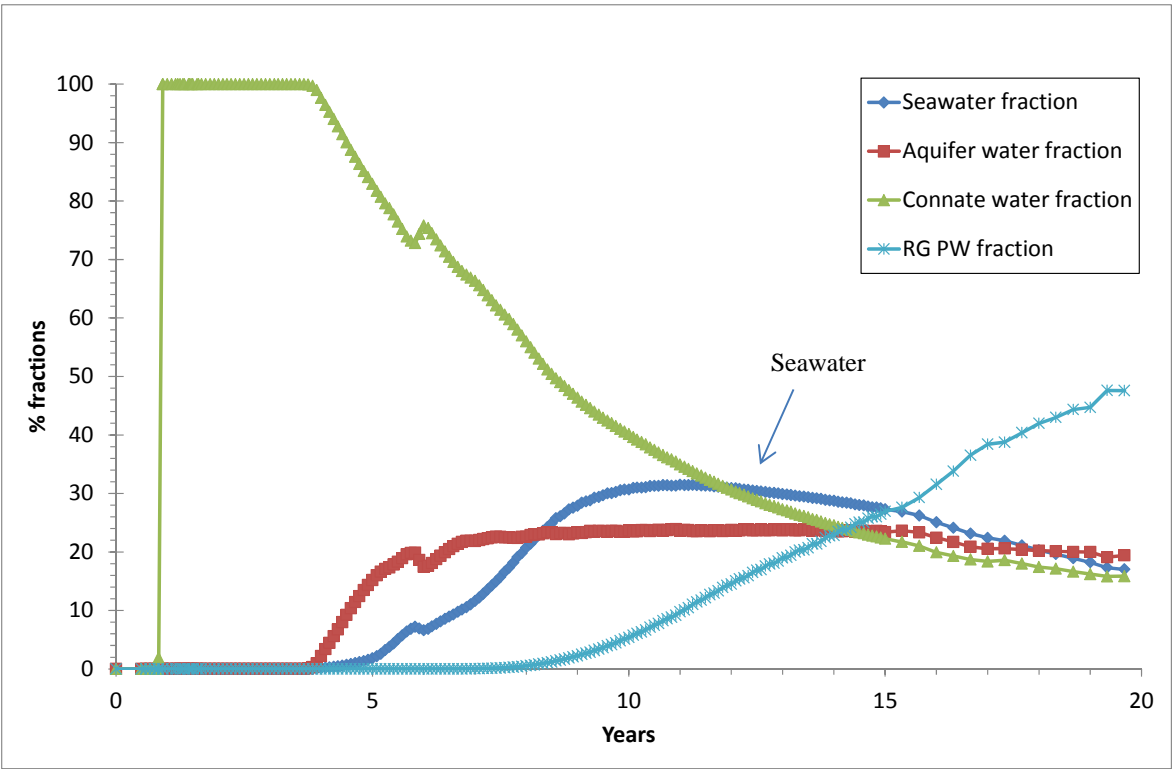


Figure 28 Fraction of brines produced in the well B1 after 5 years of seawater injection followed by PWRI

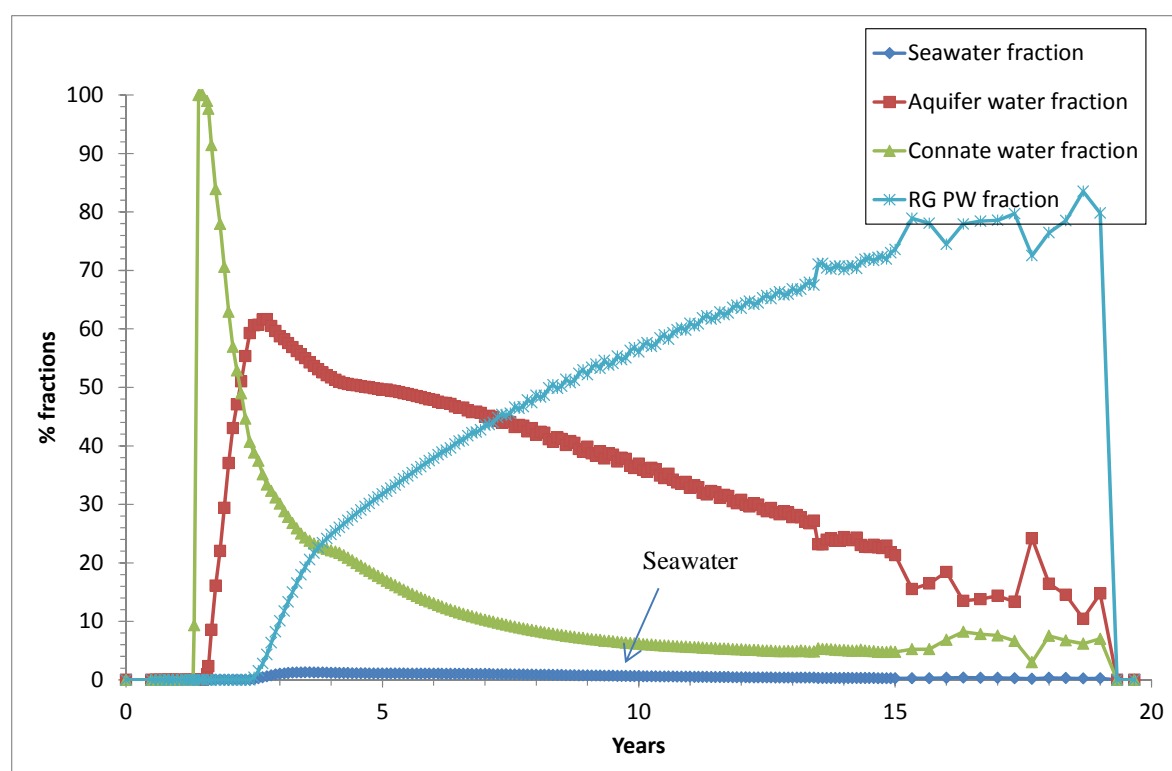


Figure 29 Fraction of brines produced in the well B2 after 1 year of seawater injection followed by PWRI

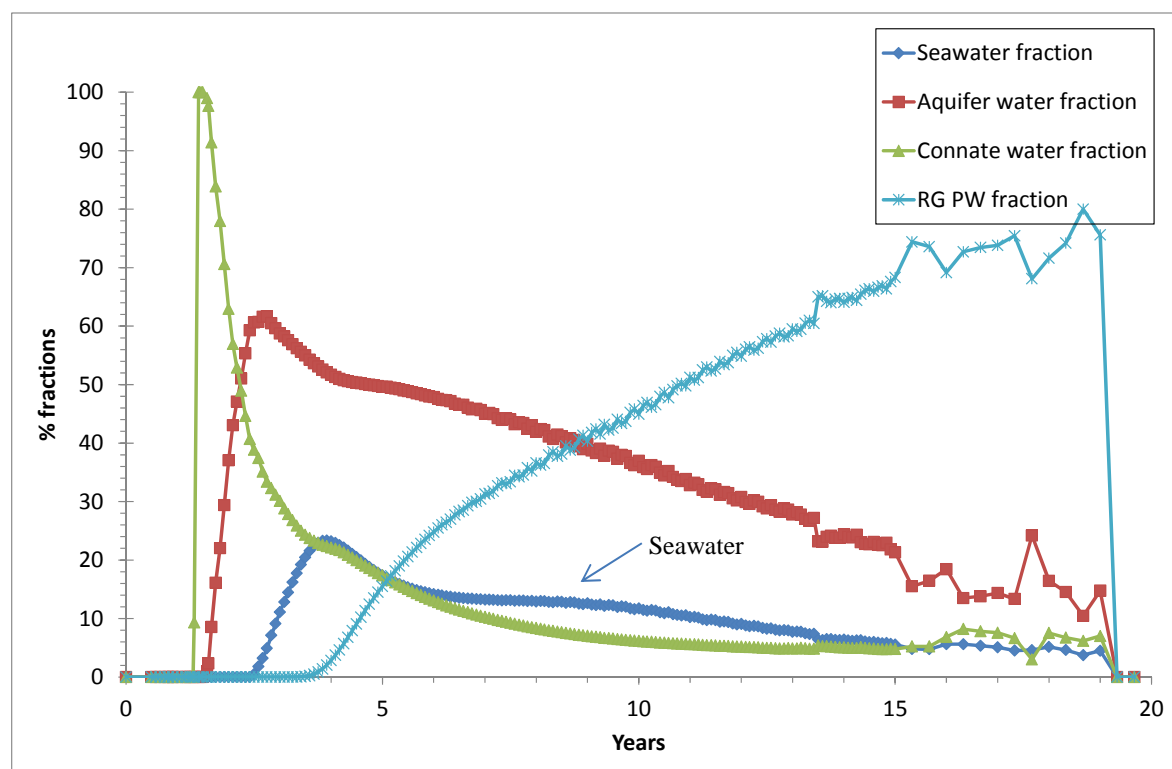
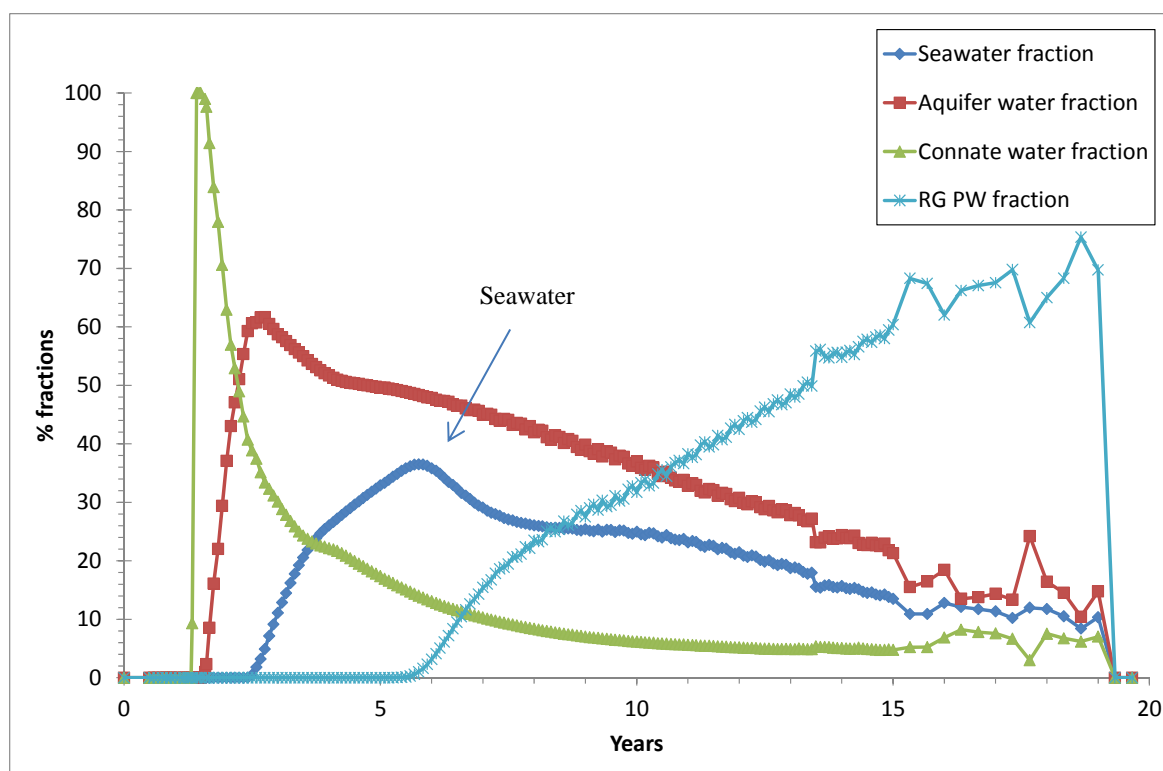


Figure 30 Fraction of brines produced in the well B2 after 3 years of seawater injection followed by PWRI



**Figure 31 Fraction of brines produced in the well B2 after 5 years of seawater injection followed by PWRI**

Both wells show the same behaviour – one year of seawater injection does not lead to significant scale risk; however, with the increase in the duration of seawater injection for more than one year, the fraction of seawater in the produced brine increases and is only replaced with re-injected Produced Water at later times (Figure 26 - Figure 31). This means that a significant  $\text{BaSO}_4$  risk in these wells would have to be managed by squeeze treatments for any period of seawater injection longer than one year.

## Conclusion

Three principal activities were performed in this study. The first enabled identification of the probable extent of the scaling problem. The second was concerned with optimising the design of squeeze treatments. The third activity was an investigation of the impact of PWRI on the  $\text{BaSO}_4$  scale risk at the producers.

Produced water rates and the percentage of seawater being produced varies across the field. Two wells B1 and B2 experience early seawater breakthrough.

Reactive transport simulation shows that the  $\text{BaSO}_4$  scale risk at the production wells will be reduced due to the effect of *in situ* reactions deep within the reservoir stripping out barium ions before the mixed brines reach the producers. This means that chemical evaluation testing based on the full unreacted brine compositions will be conservative.

The long horizontal sections of production wells will experience changes in the fractions and location of seawater flow along the well length over the lifecycle of each well.

From the point of view of mineral scale mitigation, placement of scale inhibitors during the squeeze treatments is possible for well B1 at 5 bpm, although well B2 experiences high cross flow and would benefit from a 7bpm pump rate.

Most problematic is Section 2 of the well B1. It presents a significant challenge for effective squeeze treatment placement due to the high crossflow at the heel of the lateral. A squeeze treatment at 7 bpm cannot overcome this issue.

The flow rates obtained from the reservoir simulation placement calculations were used to provide input for the SQUEEZE modelling package developed by Heriot-Watt university, which was subsequently used to design and optimise each individual squeeze design.

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